Transmission Network Investment With Probabilistic Security and Corrective Control

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***Abstract*—This paper demonstrates that the growth in application of corrective actions to enhance network utilization will require a probabilistic treatment of network security for determining efficient levels of investment in network reinforcement. A Benders decomposition based two-stage probabilistic optimization model for the operational and investment problems is proposed. For selecting relevant contingencies (beyond N-1 criteria), a novel filtering technique for efficient elimination of redundant outages is presented and successfully tested. In 2 numerical examples we compare efficiency of network reinforcement propositions under both deterministic and probabilistic frameworks, while optimizing available preventive and corrective control actions, and in particular focusing on the application of generation reserve in combination with special protection schemes (SPS) for network congestion management purposes. We highlight the inadequacies of the deterministic approach with respect to its inherent inability to optimize accurately the portfolio of pre-fault post-fault actions since the impacts of corrective actions (in the form of SPS, demand response) and occurrence of "non-credible" events require explicit consideration of the likelihood of various outages. We conclude that deterministic approach drives less efficient and potentially more risky system operation that ultimately leads to inefficient network investment.**

***Index Terms*—Corrective control, deterministic/probabilistic transmission investment, network security, unsupplied demand.**

NOMENCLATURE

A. Constants (Written in Normal Font)

$\mathrm{B}^{-1s}_{\mathrm{n,k}}$	n,k element of the inverse of the admittance matrix (only imaginary part) in operating state s [p.u].
$\mathrm{d_n}$	Demand in node n [MW].
$\underline{\mathrm{p}}_{\mathrm{g}}, \bar{\mathrm{p}}_{\mathrm{g}}$	Minimum stable generation and maximum output of generator g [MW].
$\mathrm{p}^{\mathrm{ED}}_{\mathrm{g}}$	Unconstrained dispatch of generator g [MW].
$\mathrm{voll_n}$	Value of lost load at node n [\$/MWh].
w	Duration of the standardized timeframe of all operating conditions [h].
$\mathrm{x_l}$	Reactance of line l [p.u.].
$\Delta\mathrm{resu_g}$	Net ramping up limit for generator g during the standardized timeframe [MW].
$\Delta\mathrm{resd_g}$	Net ramping down limit for generator g during the standardized timeframe [MW].
$\pi\mathrm{resh_g}$	Price of holding reserve services provided by generator g [\$/MW/h].
$\pi\mathrm{resuu_g}$	Utilization price of reserve up services provided by generator g [\$/MWh].
$\pi\mathrm{resud_g}$	Utilization price of reserve down services provided by generator g [\$/MWh].
$\pi\mathrm{itrp_g}$	Utilization price of inter-tripping schemes (SPS) provided by generator g (price per event) [\$/MW].
ρ^{S}	Probability of occurrence of operating state s.

B. Variables (Written in Italic Font)

bid_g	Accepted bid from generator g [MW].
f_l^s	Power flow in line l at operating state s [MW].
$\bar{f}_l^s$	Line rating of circuit l at operating state s [MW].
$itrp_g^s$	Tripping of generator g at operating state s by an SPS. 1 if tripped, 0 otherwise.
$itrpu_g^s$	Power tripped of generator g at operating state s by an SPS [MW].
ll_n^s	Loss of load at node n at operating state s [MW].
off_g	Accepted offer from generator g [MW].
p_g	Output of generator g [MW].
$resh_g$	Committed reserve service from generator g [MW].
$resud_g^s$	Utilized reserve down service from generator g at operating state s [MW].
$resuu_g^s$	Utilized reserve up service from generator g at operating state s [MW].
γ_g	Commitment status of generator g. 1 if on, 0 otherwise.
θ_n^s	Voltage angle of node n at operating state s [rad].

C. Set Related Constants (Written in Italic Font)

$n_1(l)$	First end node of line l.
$n_2(l)$	Second end node of line l.
Ng	Total number of generators.
Nn	Total number of nodes.

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Ns Total number of operating states.

ref Reference node or slack busbar.

I. Introduction

NETWORK security has been historically based on deterministic criteria: electricity system should be able to withstand the occurrence of any defined set of credible outages (e.g., a loss of one—N-1 criterion—or two circuits—N-2 criterion) without causing overloads or inadequate voltages on any remaining circuits/busbars, and without violating system stability limits. Post-fault network overloads, following credible contingencies, are avoided by preventive operational measures or by a combination of preventive and corrective control [1]–[3].

The underlying principle of the deterministic framework is that the system operation in a particular condition is considered to be exposed to no risk at all if the occurrence of any selected credible contingency does not violate the operational limits (with or without corrective control), while the system is considered to operate at an unacceptable level of risk if the occurrence of a credible contingency would cause some violations of operating limits [4]. Neither of these is correct, as the system is indeed exposed to risks of failure and outages even if no credible network outage leads to violations of operating constraints, and the risk of some violations may be acceptable if these can be minimized by using further post-fault corrective action. To tackle these problems, probabilistic frameworks for network security have been discussed and a number of novel approaches that assess risk profiles and balance security and economics have been proposed (for a comprehensive review, see [5]–[13]).

Although the probabilistic framework is in principle superior, in practice its additional value with respect to the deterministic approach is particularly material in the presence of significant application of corrective control. This could include, for example, generation re-dispatch, topology re-configuration, use of flexible AC transmission systems (FACTS), use of special protection systems (SPS), application of flexible demand. Furthermore, the probabilistic framework is particularly relevant when exercising corrective actions that involve cost. For example, intertripping generation post-fault or disconnecting demand post-fault, usually involves an exercise fee (e.g., in Great Britain the compensation cost associated with the tripping of a generating unit is £ 400 000 [14] and similarly cost associated with demand actions). These effects cannot be taken into account, sufficiently accurately, within a deterministic approach as the cost of exercising corrective actions need to be balanced against the associated pre-fault cost (such as constraint costs).

In this context, this paper presents a novel transmission network investment model within the probabilistic framework that optimally balances preventive and corrective controls while determining efficient transmission network reinforcements. Specifically, the presented model couples network operation and investment by means of a Benders algorithm as proposed by [15] and [17]–[23], but rather than using a deterministic security constrained optimum power flow (SC-OPF) method (like that presented by [16]) to assess the effect of operational preventive and corrective control on network investment [20], [22], [24], [25], our model considers the probabilistic realization of a set of outages (including events beyond N-1) and permits balancing a larger portfolio of pre and post-fault operational actions such as network congestion, pre-fault commitment of generation reserve, post-fault generation re-dispatch or reserve utilization, and SPS over demand and generation. It is important to mention that current probabilistic models that are able to determine network investment, have a limited consideration of the impact of corrective control on network investment [17], [21], [26]–[28]. Also, network reinforcements are undertaken by examining an array of system operating conditions (demand levels) and operating states (i.e., outages of generation and transmission components) taking into account effects of weather conditions.

In addition, a novel contingencies-selection or filtering technique that is able to interact with the primary Benders algorithm, is proposed to select relevant contingent events as the optimization is not limited to the occurrence of pre-defined outages only (i.e., N-1). Furthermore, our filter differs from those that select outages based on probability thresholds [6], performance indexes (including risk-based indexes) and constraints violations [30], [31], and Monte Carlo simulation [17], [29] since it explicitly constrains the impact of considering a subset of contingencies by sampling (and eliminating) only the scenarios that are the most (least) relevant in terms of their contribution to the overall cost-plus-risk objective function (i.e., value of probability times cost consequence, including the risk of unsupplied demand and generation shedding through SPS). Additionally, unlike approaches based on Lagrange multipliers that can also identify the relevant outages by assessing their contribution to the costs-plus-risks objective function [32], our filter identifies the relevant outages without the need to run the operational or planning optimization over the entire set of N-k outages initially given. The proposed filter can be used for both operational and planning studies.

We compare network investment propositions under both the deterministic and the probabilistic approaches while considering preventive and corrective control. We demonstrate that the resulting network operation and investment under deterministic approach will be inefficient, due to unnecessary overinvestment or/and increased exposure to risks above efficient levels, since there is inadequate assessment of actual post-fault costs, demand curtailment risks and “non-credible” events.

This paper is organized as follows. Section II formulates the optimization model that considers different pre-fault operational measures and post-fault corrective actions to support transmission operation and investment. Sections III and IV shows the numerical analyses. Finally, Section V concludes and suggests topics for further work.

II. Description of the Network Investment Model

The proposed model is composed of operational, investment and filtering (contingencies-selection) modules presented in Fig. 1. In the operational module, the optimal probabilistic dispatch and so the optimum network utilization over a given operating condition is determined when considering the use of corrective control. The investment module, supported by multiple executions of the operational module over a variety of operating conditions, determines: 1) the optimum network investment in a year, 2) the optimum generation commitments in each operating condition, and 3) the utilization of SPS in each

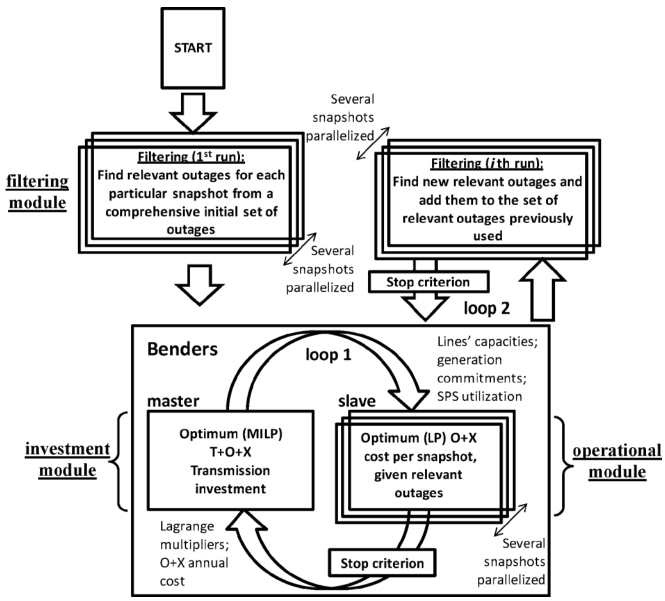

Fig. 1. General algorithm with 3 modules.

operating state. The operating and investment decisions are coordinated through a Benders algorithm. The filtering module serves to limit the number of operating states considered in the optimization and is applied iteratively as follows:

— finding the relevant outages over the initial network for each operating condition (1st run in Fig. 1);

— finding the relevant outages over the enhanced network for each operating condition, and adding these outages (if not included) to the previously found set of relevant outages (ith run in Fig. 1).

The Benders algorithm (loop 1) stops according to the general criterion explained in [33] which is when the upper (Z_upper) and lower (Z_lower) estimations of the overall transmission cost function (i.e., investment (T) + operation (O) + unsupplied demand (X)) are nearly equal.

Loop 2 stops if there are no more outages to be added to the set of relevant outages given the latest sets of transmission network capacities and generation outputs.

To reduce the potentially substantial computational burden in larger networks, parallel threading is used (Fig. 1 shows how different operating conditions can be run in parallel) together with a heuristic procedure that searches the (nearly) optimum solution of the mixed integer linear programming (MILP) problem within a given duality gap. This is detailed next.

A. Operational Module: Optimizing Network Utilization $(O+X)$

This module determines the optimum power transfers across transmission network by balancing the cost of the transmission constraints against the cost of applying pre-fault operational measures and post-fault corrective actions. This optimization is carried out considering a single operating condition under a set of outages that are weighted according to their probabilities, which will depend on weather as proposed in [34].

The pre-fault operational measures and post-fault corrective actions considered in this model show the benefits of the probabilistic framework and the problems of using such measures under the deterministic method.

1) *System balancing*. Power flows can be controlled via generation balancing actions in order to mitigate circuit overloading while maintaining the supply and demand balance at all times.
2) *Allocation and utilization of generation reserve*. Different levels of generation reserve can be allocated in the pre-fault condition (via balancing actions) to efficiently deal with outage events in a post-fault condition. In this model, generation reserves are allocated and utilized in order to deal with outages not only of generating plants but also of transmission circuits. Consequently, the reserve is spatially optimized to facilitate the application of SPS. The reserve can be provided by synchronized generators and/or through units providing standing reserve of appropriate dynamic characteristics.
3) *Exercise of SPS to curtail generation and/or demand*. Following an outage of a circuit, SPS automatically disconnects (or instigate rapid reduction of) generation and demand in exporting and importing areas respectively, to avoid post-fault network overloads. This allows increased levels of power transfers in the pre-fault condition and hence results in reduced levels of network constraints.

Therefore, the objective function of the proposed operational model has to balance all these costs and expected costs (or risks) as shown in (1) at the bottom of the page.

In the model, the first operating state is the intact system or pre-fault state $(\mathrm{s}=1)$ and this is coupled with all considered contingent states in order to determine the optimal portfolio of preventive (pre-fault) measures and post-fault actions. Given the intact system condition (with optimized generation outputs and reserve), optimization of post-fault states involves changes in generation outputs and demand (through demand response—DR) while taking into account generation ramp rate limits, SPS actions and the operating reserves committed in the intact system. In addition, line ratings can be considered

$$Min\left\{\begin{array}{l}\sum\limits_{g=1\ldots Ng}\{\mathrm{w}\cdot(\pi\mathrm{off_g}\cdot off_g-\pi\mathrm{bid_g}\cdot bid_g+\pi\mathrm{resh_g}\cdot resh_g)\}+\\ \sum\limits_{\substack{s=2\ldots Ns\\ g=1\ldots Ng}}\left\{\mathrm{w}\cdot\rho^{\mathrm{s}}\cdot\left(\pi\mathrm{resuu_g}\cdot resuu_g^s+\pi\mathrm{resud_g}\cdot resud_g^s\right)\right\}+\\ \sum\limits_{\substack{\mathrm{s\ with\ line\ trips}\\ g=1\ldots Ng}}\left\{\rho^{\mathrm{s}}\cdot\pi\mathrm{itrp_g}\cdot itrp_g^s\right\}+\sum\limits_{\substack{s=2\ldots Ns\\ n=1\ldots Nn}}\left\{\mathrm{w}\cdot\rho^{\mathrm{s}}\cdot\mathrm{voll}_n\cdot ll_n^s\right\}\end{array}\right\} \quad (1)$$

temporarily larger during post-fault conditions. The model considers that all operating actions occur within a limited standardized timeframe with duration w (e.g., 30 min).

Cost of pre-fault preventive measures is determined through the departure from unconstrained economic dispatch through increases (offer volumes) and decreases (bid volumes) of generation outputs in the intact system. This is shown in (2). Given the structure of the objective function, a positive $\pi\mathrm{off}_{\mathrm{g}} - \pi\mathrm{bid}_{\mathrm{g}}$ differential will ensure that bids and offers are not simultaneously accepted for a single generator. Power outputs and balancing actions must also respect generating output limits (3)–(7):

$$p_g = \mathrm{p}_g^{\mathrm{ED}} + off_g - bid_g \quad \forall g \tag{2}$$
$$off_g \leq \bar{\mathrm{p}}_g - \mathrm{p}_g^{\mathrm{ED}} \quad \forall g \tag{3}$$
$$bid_g \leq \mathrm{p}_g^{\mathrm{ED}} \quad \forall g \tag{4}$$
$$\underline{\mathrm{p}}_g \cdot \gamma_g \leq p_g \leq \bar{\mathrm{p}}_g \cdot \gamma_g \quad \forall g \tag{5}$$
$$\gamma_g \text{ is binary} \quad \forall g \tag{6}$$
$$p_g \leq 0 \quad \forall g \text{ in maintenance.} \tag{7}$$

The corrective actions from the generation side are represented as follows: in order to have reserve available for re-dispatching purposes, it must be committed in advance (8)–(10); reserves have to also respect certain limits (11)–(12); and SPS, if used, will curtail the entire production (including post-fault reserve) of a generating unit (13)–(17):

$$resh_g \leq \bar{\mathrm{p}}_g - p_g \quad \forall g \tag{8}$$
$$resh_g \leq \Delta\mathrm{resu}_g \cdot \gamma_g \quad \forall g \tag{9}$$
$$resuu_g^s \leq resh_g \quad \forall s, g \tag{10}$$
$$resud_g^s \leq \Delta\mathrm{resd}_g \quad \forall s, g \tag{11}$$
$$p_g - resud_g^s \geq \underline{\mathrm{p}}_g \cdot \gamma_g \quad \forall s, g \tag{12}$$
$$resuu_g^s \leq \Delta\mathrm{resu}_g \cdot (1 - itrp_g^s) \quad \forall s, g \tag{13}$$
$$resud_g^s \leq p_g - itrpu_g^s \quad \forall s, g \tag{14}$$
$$p_g - itrpu_g^s \leq \bar{\mathrm{p}}_g \cdot (1 - itrp_g^s) \quad \forall s, g \tag{15}$$
$$itrpu_g^s \leq \bar{\mathrm{p}}_g \cdot itrp_g^s \quad \forall s, g \tag{16}$$
$$itrp_g^s \text{ is binary} \quad \forall s, g. \tag{17}$$

All other constraints represent equalities and inequalities of an optimum power flow (OPF) exercise with transmission constraints such as: the supply-demand balance in pre- and post-fault conditions (18)–(20); the voltage angle equations considering a linearized (DC) power flow (21)–(22); and the power flow per line along with its limits (23)–(25). Due to the complexity of the presented model, the n,k element of the susceptance matrix B in (22) changes with outages, but does not change with network reinforcements and this is suggested to be further developed. For this purpose, the disjunctive approach explained in [18] and [19] arises as a particularly interesting method to be explored and potentially applied within the presented probabilistic framework. See (18)-(25) at the bottom of the page.

This formulation corresponds to a MILP problem if the operational module is run in isolation from the investment module. Instead, this formulation corresponds to a linear programming (LP) problem if the decisions associated with generation commitments and SPS utilization levels are imported from master subproblem of the Benders algorithm (the investment module). In this case the operational module becomes a slave subproblem and the SPS cost can be ignored in (1). All continuous variables can be zero or take positive values with the exemption of the power flows and voltage angles that can also take negative values.

B. Investment Module: Optimizing Network Capacity $(T+O+X)$

In investment timescales, the operating costs and risks associated with proposed transmission network reinforcement are measured and summed over the entire year which is represented by a set of operating conditions. This is required to determine the efficient levels of transmission investment that is balanced against the cost associated with pre-fault operational measures and post-fault corrective actions.

For each operating condition where the operational module (i.e., slave subproblem) is executed, the Lagrange multipliers associated with the following constraints are exported to the master subproblem: lower and upper bounds of lines' capacity (24); minimum and maximum generation capacities (5);

$$\sum_{g=1\ldots Ng} p_g = \sum_{n=1\ldots Nn} \mathrm{d}_n - \sum_{n=1\ldots Nn} ll_n^{s=1} \tag{18}$$
$$\sum_{\substack{g\ available\\ in\ s}} p_g + resuu_g^s - resud_g^s - itr_g^s = \sum_{n=1\ldots Nn} \mathrm{d}_n - ll_n^s \quad \forall s = 2\ldots Ns \tag{19}$$
$$resuu_g^s = 0; resud_g^s = 0; itr_g^s = 0 \quad \forall s = 2\ldots Ns, g \text{ outaged} \tag{20}$$
$$\theta_{n=ref}^s = 0 \quad \forall s \tag{21}$$
$$\theta_n^s = \sum_{\substack{k=1\ldots Nn\\ k\neq ref}} \left[\left(\sum_{\substack{g \text{ available}\\ \text{at node k in s}}} \left(p_g + resuu_g^s - resud_g^s - itr_g^s\right) + ll_k^s - \mathrm{d}_k \right) \cdot \mathrm{B}_{n,k}^{-1\ s} \right] \quad \forall s, n \neq ref \tag{22}$$
$$f_l^s = \frac{\theta_{n_1(l)}^s - \theta_{n_2(l)}^s}{\mathrm{x}_l} \quad \forall s, l \text{ available} \tag{23}$$
$$-\bar{\mathrm{f}}_l^s \leq f_l^s \leq \bar{\mathrm{f}}_l^s \quad \forall s, l \text{ available} \tag{24}$$
$$f_l^s = 0 \quad \forall s, l \text{ outaged} \tag{25}$$

maximum generation reserve holding levels (9); maximum generation reserves utilization (12)–(13); and the utilization of SPS (15)–(16). Given these multipliers, it is possible to run the master subproblems by adding iteratively Benders cuts as detailed in [33]. This is carried out over an array of operating conditions that are weighted according to their duration. Overall, the annuitized transmission investment cost is balanced against operational cost and risk over a year.

Although the solution of this MILP problem can take a considerable amount of time to be determined, the equivalent LP problem [with (6) and (17) relaxed] can be solved significantly faster, where the final continuous solution can be corrected and made feasible for the MILP problem by implementing a standard local search algorithm.

C. Filtering Module: Finding the Relevant or Umbrella Outage States

According to [32], the set of umbrella contingencies in a probabilistic assessment is a subset of the full set of all contingencies that is sufficient to attain levels of security and economic performance that is very close to the one obtained when all contingencies are considered.

In the proposal presented in this paper, the set of umbrella outages is determined by undertaking a risk assessment (that quantifies all the expected post-fault costs by using the algorithm in Section II-D) of each individual outage (contained in a comprehensive initial set) over a given intact system dispatch (i.e., set of pre-fault generation outputs and reserve allocation). This is carried out in several iterations as follows:

1) define the set of umbrella outages as an empty set;
2) execute the operational module over the targeted operating condition when considering only the occurrences of the umbrella outages and obtain the optimum dispatch solution (in the first iteration, consider the occurrence of no outages to obtain the "N-0" optimum dispatch);
3) assess the risk associated with each individual event that is outside the set of umbrella outages (by using the algorithm in Section II-D) over the intact system dispatch solution obtained in the previous step. The outage with the largest risk is identified and added to the set of umbrella outages;
4) sum the risks over all outages that are left outside the set of umbrella outages. If this sum is lower than a tolerance value predefined by the user (in \$), stop. Otherwise, go to 2).

By definition, the outages left outside the set of umbrella outages will not cause severe risks for the system operation. In fact, it can be proven that the difference (or error incurred) in the overall operating cost-plus-risk [measured by (1)] between the optimization with all outages and that with only the umbrella outages is lower than or equal to the given tolerance value.

D. Risk Assessment of a Given Intact System Solution

The assessment of the expected post-fault costs associated with a given intact system dispatch is carried out by executing the probabilistic operational module (over the corresponding operating condition and over a given set of operating states) with *2xNg* extra constraints that force the intact system's output and reserve holding level of each generator to be equal to those from the given intact system dispatch. The resulting post-fault cost will be equal to (1) minus the pre-fault cost.

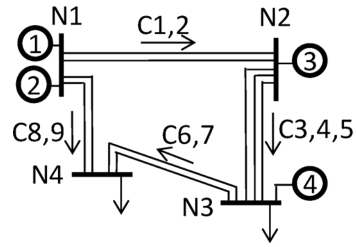

Fig. 2. 4-node system topology (positive flows defined by arrows).

TABLE I
4-NODE SYSTEM'S GENERATION AND NETWORK DATA

	Rating [MW]	λ [occ/yr]
C1	65	0.1
C2	65	0.1
C3	50	depend
C4	50	on
C5	50	weather
C6	15	0.1
C7	15	0.1
C8	90	0.1
C9	90	0.1

Generator	Capacity	Minimum generation	Ramp up/down	Fuel/bid/offer	Reserve up/down	λ
	MW			\$/MWh		occ/yr
G1	200	50	150	10	10	18
G2	200	50	150	11	11	18
G3	200	100	100	20	20	18
G4	100	70	30	25	25	18

E. Deterministic Network Operation and Investment Model

The deterministic version of the proposed probabilistic model corresponds to an optimization equal to the probabilistic one (in both operation and investment) but that considers: only N-1 outages (no filtering module used); all state probabilities equal to 1; price of generation-based post-fault actions approaching zero (i.e., SPS, generation re-dispatches/reserves utilization); and price of demand shedding approaching infinity (i.e., no demand shedding is allowed under the occurrence of a credible outage).

Once obtained the deterministic N-1 solution, its real cost and risk can be measured by the probabilistic equation (1) when considering outages beyond those credible and by using a process like that illustrated in Section II-D. In this process, it is considered an optimum post-fault utilization of operational measures (including demand shedding) under non-credible events. This will tend to underestimate the risks associated with the non-credible outages because, in the deterministic framework, network operation and investment is not necessarily planned to cope with this type of events.

III. SMALL-SCALE STUDY: ILLUSTRATION, VALIDATION, AND ANALYSIS OVER A 4-NODE NETWORK

The study presented in this section intends to inspect the performance of the probabilistic security approach when optimizing network utilization and investment with corrective control. Results are then compared with those of the deterministic framework. The small network serves to illustrate and validate the proposed model.

A. Network Description

The test system is composed of 4 nodes, 9 circuits, 4 generators, and 2 loads. Topology and other relevant data are given in Fig. 2 and Table I.

TABLE II
GENERATION OUTPUTS AND NETWORK UTILIZATIONS

		Probabilistic		Deterministic
		Fair weather	Adverse weather	All weather
Generation [MW]	G1	150	80	50
	G2	50	50	50
	G3	0	0	100
	G4	0	70	0
Transfers [MW]	C1+C2	82	44	9
	C3+C4+C5	82	44	109
	C6+C7	-18	14	9
	C8+C9	118	86	91

TABLE III
COSTS AND RISKS OF THE PROBABILISTIC AND DETERMINISTIC SOLUTIONS

		Cost of [$/30min]				
		Constraints	Reserve utilization	SPS	DR	Total O+X
Probabilistic	Fair weather	27.5	1.1	0.0	6.1	35
	Adverse weather	556.0	1.1	0.0	2.2	559
Deterministic	Fair weather	532.5	1.1	0.2	0.6	534
	Adverse weather	532.5	1.6	284.4	533.3	1352

TABLE IV
POST-FAULT COSTS (UPPER) AND POST-FAULT CORRECTIVE ACTIONS (LOWER) OF RISKY OPERATING STATES

	Expected cost of [$/30min]							
	Fair weather				Adverse weather			
	Probabilistic		Deterministic		Probabilistic		Deterministic	
Outage	SPS	DR	SPS	DR	SPS	DR	SPS	DR
C1	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0
C2	0.0	0.9	0.0	0.0	0.0	0.0	0.0	0.0
C8	0.0	0.4	0.0	0.0	0.0	0.4	0.0	0.0
C9	0.0	0.4	0.0	0.0	0.0	0.4	0.0	0.0
G1+G2	0.0	3.2	0.0	0.2	0.0	1.5	0.0	0.2
C3+C4	0.0	0.1	0.1	0.1	0.0	0.0	94.8	177.7
C3+C5	0.0	0.1	0.1	0.1	0.0	0.0	94.8	177.7
C4+C5	0.0	0.1	0.1	0.1	0.0	0.0	94.8	177.7

	Corrective actions (DR in [MW]node3-[MW]node4 and SPS in unit tripped)							
	Fair weather				Adverse weather			
	Probabilistic		Deterministic		Probabilistic		Deterministic	
Outage	SPS	DR	SPS	DR	SPS	DR	SPS	DR
C1	-	10-0	-	0-0	-	0-0	-	0-0
C2	-	10-0	-	0-0	-	0-0	-	0-0
C8	-	0-5	-	0-0	-	0-5	-	0-0
C9	-	0-5	-	0-0	-	0-5	-	0-0
G1+G2	-	100-100	-	0-12	-	0-100	-	0-12
C3+C4	-	25-0	G3	25-0	-	0-0	G3	25-0
C3+C5	-	25-0	G3	25-0	-	0-0	G3	25-0
C4+C5	-	25-0	G3	25-0	-	0-0	G3	25-0

The transmission link composed of C3,4,5 has a higher failure rate (λ) which is also dependent on weather: 0.0011 and 0.0457 occ/h during a fair and an adverse weather hour, respectively. Additionally, the Value of Lost Load (VoLL) and the utilization price of SPS are assumed to be 30 k$/MWh and 200 k$ per generating unit tripped, respectively. For the sake of simplicity, offer and bid prices are equal to fuel prices as well as reserve up and down prices; the availability price of reserve is neglected; and post-fault line ratings are equal to the pre-fault ones.

The model considers initially 92 potential operating states that represent all N-1 (13 events) and all N-2 outages (78 events) plus the intact system. The probability of each state is calculated assuming that all outage events are independent and exponentially distributed as expressed by (26)–(27):

$$\rho^{\mathrm{s}} = \prod_{i \in \mathrm{U^s}} (1 - \mathrm{Pr_i}) \prod_{j \in \mathrm{D^s}} (\mathrm{Pr_j}), \quad \text{where} \tag{26}$$

$$\mathrm{Pr_i} = 1 - e^{-\lambda_{\mathrm{i}} \times \mathrm{T}}. \tag{27}$$

$\mathrm{Pr_i}$ is the probability of finding network component i outaged over time T, and $\mathrm{U^s}$ and $\mathrm{D^s}$ are the sets of components in and out at operation state s, respectively.

Finally, a year with 2 operating conditions is considered for planning studies: a peak (100 MW in each node 3 and 4) and off-peak demand (60 MW in each node 3 and 4).

B. Network Utilization With Corrective Control

The unconstrained economic dispatch (without considering network constraints) for peak demand condition involves operating most efficient unit G1 at full output. However, this dispatch solution is exposed to demand curtailment under the occurrence of several outage events, including the single failures of G1, C8 and C9. This is unacceptable within an N-1 deterministic approach and can be proved inefficient under the probabilistic model. Hence, the solution has to be modified through balancing actions in both models. The optimum solutions are presented in Table II.

There are two probabilistic solutions since risks of network failures are different in fair and adverse weather. The shown deterministic solution is obtained by considering N-1 events only, constraining the use of DR, and permitting the use of further corrective control measures at no cost (as explained in Section II-E). Costs and risks of the deterministic and probabilistic solutions are shown in Table III.

The risks under fair and adverse weather of the deterministic dispatch are measured by the probabilistic process described in Section II-D and when considering all N-1 and N-2 outages. In Table IV, major outages (that drive higher risks) are presented along with the most expensive corrective actions associated with generation and demand curtailment.

An interesting characteristic of the probabilistic solution is that during both fair and adverse weather there is exposure to demand being curtailed under N-1-type outages (see Table IV). This exposure is eliminated by the deterministic solution and no re-dispatch actions are needed under any network single outage condition.

However, the deterministic dispatch is actually exposed to a higher risk of demand and generation curtailment, which is mainly driven by a set of double circuit outages in C3,4,5 (Tables III and IV). Additionally, although the deterministic solution does decrease the levels of risk under fair weather, it is found to be more expensive during pre-fault. Note that the deterministic dispatch is inefficient with respect to the total cost in both fair and adverse weather (see Table III).

Furthermore, the utilization of the network is fundamentally different between the solutions shown in Table II: although the net transfers from the exporting (nodes 1 and 2) to the importing (nodes 3 and 4) area are the same in the probabilistic and deterministic solutions during fair weather, the power flows in C8,9 are increased by the probabilistic method in order to minimize the balancing (or constraints) cost and the utilization of more

TABLE V
COSTS AND RISKS OF THE DETERMINISTIC (UPPER) AND PROBABILISTIC SOLUTIONS (LOWER)

	Cost of [k$/yr]					
	T	O + X				T+O+X
	Investment	Constraints	Reserve utilization	SPS	DR	Total
Deterministic	40	482	12	0	81	615
Probabilistic	0	528	12	0	36	576

costly corrective actions (i.e., SPS of G3) under a double circuit outage in C3,4,5. Notice that this solution still considers the action on demand side during double circuit outages in C3,4,5 (see Table IV). The net transfers between the exporting and importing areas, on the other hand, are significantly reduced under adverse weather (in the probabilistic solution) in order to eliminate costs associated with the utilization of corrective control under double circuit outages in C3,4,5 that would become significantly more probable given the increase in the likelihood of line outages under this weather condition. Note that this solution considers the commitment of the most expensive generating unit G4 and the action on demand side during single circuit outages in C8,9 (see Table IV).

C. *Network Investment With Corrective Control*

In order to determine the optimal network capacities, annual operating costs-plus-risks are balanced against annuitized network investment costs. For the purpose of illustrating the differences between deterministic and probabilistic approaches, we studied 4 conditions: peak and off-peak demand condition (with the duration of one year) combined with fair and adverse weather. The time duration of (t1) the peak and fair weather, (t2) off-peak and fair weather, (t3) peak and adverse weather, and (t4) off-peak and adverse weather condition are 394, 7490, 44, and 832 h, respectively. The probabilistic and deterministic planning solution for an investment costs of 3500 $/MW/yr (where length has been already incorporated) is shown in Table V where C6,7 is enhanced by 5.7 MW and C8,9 is also enhanced by 5.7 MW by the deterministic method.

The first point to notice is that the deterministic planning does not necessarily solve the problem of high risk exposure because, as indicated earlier, this risk can be driven by events that are beyond the set of secured outages considered (a double circuit outage in C3,4,5 under adverse weather conditions).

Second, we can observe that under the probabilistic approach no investment is needed and, in fact, the set of pre-fault operational measures and corrective actions deployed (some of those explained in the previous section) is sufficient to achieve both lower levels of overall costs and risks.

D. *Sensitivity Analysis*

A sensitivity analysis in the cost of network investment, VoLL and the utilization price of SPS shows that while enhancements are undertaken in links C6,7 and C8,9 under the deterministic solution (that by definition is insensitive to VoLL and the utilization price of SPS, and that also resulted insensitive to the investment cost in this case), under the probabilistic model enhancements are preferable in links C3,4,5 and C6,7 for a wide range of potential values of investment cost, VoLL and utilization price of SPS. For example, Table VI shows how network investment and DR change with VoLL and SPS prices for an investment cost of 700 $/MW/yr.

TABLE VI
NETWORK INVESTMENT AND YEARLY DEMAND RESPONSE FOR VARIOUS VOLL AND SPS PRICES

Corrective control price	VoLL [k$/MWh]	1	...	13	14	15	16	17	18	19	20	21	...	30
	SPS [k$/unit]	7	...	87	93	100	107	113	120	127	133	140	...	200
Probabilistic investment and DR	C3+C4+C5 [MW]	0		0	10	10	10	10	10	21.4	21.4	30		30
	C6+C7 [MW]	0		0	0	0	0	0	0	5.7	5.7	10		10
	DR [MWh]	2.7		2.7	2.3	2.3	2.3	2.3	2.3	1.6	1.6	1.2		1.2
Deterministic investment and DR	C6+C7 [MW]	5.7		5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7		5.7
	C8+C9 [MW]	5.7		5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7	5.7		5.7
	DR [MWh]	2.7		2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7		2.7

TABLE VII
UMBRELLA STATES PER ITERATION FOR FAIR (UPPER) AND ADVERSE (LOWER) WEATHER IN THE PEAK DEMAND CONDITION

Iteration	1	2	3	4	5	6	7	8	9	10	11	Risk of remaining outages [$/30min]
Outage fair weather	G1	G2	G1 + G2	C1	C2	C8	C9	C3 + C4	C3 + C5	C4 + C5	G1 + C1	0.02
Outage adverse weather	G1	G2	C3 + C4	C3 + C5	C4 + C5	G1 + G2	G1 + G4	G2 + G4	G4	G1 + C3	/	0.07

Table VI demonstrates that deterministic and probabilistic investment are consistent with the utilization levels observed in operational timescales under each framework, and proves that the probabilistic solution is different to that deterministic for any VoLL and SPS prices studied. Furthermore, the inefficient (non-optimal) application of pre-fault operational measures and corrective actions driven by the deterministic framework will not only drive under/over investment but also potentially investment in wrong circuits.

Table VI also illustrates that further preventive actions, such as network investment, may need to be undertaken when VoLL and SPS prices increase, in order to make a more cost-effective utilization of costly corrective actions and thus limit escalating risks.

E. *Algorithm Performance: Umbrella States*

The umbrella states of the peak demand condition during fair and adverse weather are obtained by using the proposed algorithm. Only 11 and 10 outages during fair and adverse weather, respectively, are classified as umbrella when considering a tolerance value equal to 0.1 $/30 min. Table VII shows the results of the filtering module per iteration.

The sets of 11 and 10 umbrella contingencies for fair and adverse weather, respectively, drive the same operational solution as the initial 91-outage set, being the sum of risks of the outages that are outside these umbrella sets less than 0.02 and 0.07 $/30 min for fair and adverse weather, respectively.

The outages in Table VII also drive the optimum solution in investment (together with the umbrella states of t2 and t4) by carrying out only one iteration of loop 2 (see Fig. 1).

IV. IEEE RTS STUDY

In this section we apply the proposed probabilistic framework on the 24-node IEEE RTS. Further differences in the proba-

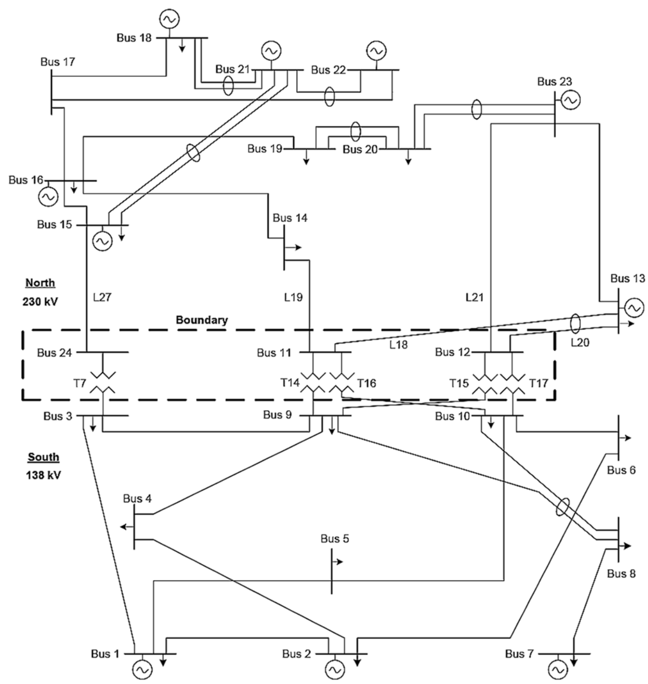

Fig. 3. IEEE RTS network and the defined boundary.

bilistic and deterministic frameworks for network investment are illustrated, especially regarding the impact of generation reserve allocation in supporting transmission congestion management and investment.

A. Network Description

The IEEE RTS contains 32 generators and 38 lines. In [35], all generation (e.g., installed capacities, ramp rates, failure rates, technologies, etc.) and transmission figures (e.g., admittances, length, failure rates, ratings, etc.) can be found. With respect to the operating conditions, a year is divided into summer and winter through 40 demand periods. We assume that adverse weather corresponds to 12% of the winter period, with probabilities of circuit outages being 32 times higher than during fair weather (failure rates in [35] are assumed to occur under fair weather).

In this exercise we focus on the main North to South boundary of the system, as indicated in Fig. 3. The set of forced outages considers all N-1 events of generation and transmission across the system including relevant N-2 line events that affect the targeted boundary (109 operating states considering the intact system). Generation and line maintenance are also considered.

The relevant cost data is taken from [36], with additional assumptions: 1) VoLL is assumed to be 1 k$/MWh, 2) the SPS utilization cost at 7 k$ per unit tripped, 3) the reserve availability cost of 15 $/MW/h, and 4) bid (and reserve down)/offer (and reserve up) prices are assumed to be equal to the fuel prices divided/multiplied by a factor of 1.1, respectively.

Transmission investment is considered to be 60 $/MW/km/year and post-fault line ratings are 25% higher than those pre-fault.

TABLE VIII
CAPACITY AND PRE-FAULT ANNUAL UTILIZATION LEVELS OF THE BOUNDARY

		Deterministic		Probabilistic	
		Δcapacity [MW]	Average utilization [%]	Δcapacity [MW]	Average utilization [%]
Substation	T7	0	88%	100	72%
	T14	200	51%	100	62%
	T15	200	50%	100	62%
	T16	200	29%	100	36%
	T17	200	28%	100	36%
Line	L18	0	19%	0	21%
	L19	100	63%	100	64%
	L20	0	21%	0	22%
	L21	0	73%	0	76%
	L27	0	71%	0	72%

B. Case Study Description

The connection of 3 new participants is analyzed: 1 GW of new peak demand in node 7 (importing South) and 500 MW of new generation in node 13 and 500 MW of new generation in node 16 (both nuclear in exporting North). The aim is to assess the need for enhancing the transmission capability of the North-South boundary, through use of preventive and corrective measures together with network reinforcements, while considering costs and risks under the deterministic and probabilistic methods.

C. Results

Table VIII shows the increases in boundary's network capacities and their average utilization levels obtained by the deterministic and probabilistic models.

Results demonstrate that the ultimate capacities driven by the probabilistic model are associated with higher levels of utilization. In fact, utilization levels in the deterministic solution are limited by the (non-optimal) amount of reserve allocated in the importing area that can support network utilization through generation re-dispatch actions in a post-fault situation. Under the probabilistic approach, generation reserves allocated in the importing area in addition to the support enabled by the demand side, can support higher levels of network utilization.

It is interesting to note that the proposed reinforcements of some circuits are larger in the probabilistic than in the deterministic solution. For example, the enhancement of T7 by 100 MW in the probabilistic solution increases the capacity of the corridor (composed of T7 and L27) from 400 MW to 500 MW that is fully used in high-transfer conditions. Because the power transfers are more limited in the deterministic solution (due to limited reserve), there has been no need to increase the capacity of this corridor.

Under the deterministic solution, reinforcements are generally larger, as shown in Table VIII. For example, the enhancements of T14-17 in the deterministic solution can be justified by the need to accommodate an N-1 outage of a transformer in substations T14-17. Under the probabilistic model, on the other hand, the rare event of a transformer outage is more efficiently managed through demand side actions.

Overall, total costs of transmission reinforcements are higher in the deterministic approach. On the other hand, its operating costs are not lower with respect to the probabilistic solution. In fact, operational costs can increase under the deterministic model despite excessive network capacity reinforcements, due

TABLE IX
ANNUAL COSTS AND RISKS OF THE DETERMINISTIC AND PROBABILISTIC SOLUTIONS

	Cost of [k$/yr]						
	T	O				X	T+O+X
	Investment	Constraints	Reserve holding	Reserve utilization	SPS	DR	
Deterministic	17255	82052	52132	250	1	3	151693
Probabilistic	11680	62192	47339	208	2	352	121773

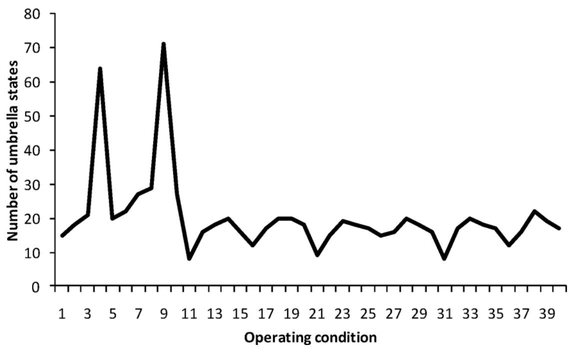

Fig. 4. Number of umbrella states per operating condition.

to its limitations to make use of an optimum mix of reserve and DR to enhance the utilization of the network. This is shown in Table IX.

Umbrella States: The number of operating states that drive the optimum decision is considerably lower than the ones initially considered. In fact, about 20 outages are needed to be considered in the optimization of most of the operating condition. Only during the peak demand period the number of umbrella outages increases to circa 65 and 75 events (during fair and adverse weather in winter, respectively). This is shown in Fig. 4.

Due to the reduced number of umbrella states, the computation time needed to obtain the optimum operational solution over a given demand condition can be decreased from about 9 (time used when no outages are filtered) to 1.5 s in average. In planning timescales, the improvement in computation times achieved by applying the proposed filter is complemented by the employment of parallel processing which serves to run the $\mathrm{O}+\mathrm{X}$ optimization of an array of operating conditions at the same time. According to the number of parallel processes executed, computation times can be reduced by a factor between 4 and 5 as shown in Fig. 5 that depicts the time used by the Benders process in obtaining the relaxed solution of both the $\mathrm{T}+\mathrm{O}+\mathrm{X}$ optimization with all operating states and with only the umbrella outages. To obtain these results, FICO Xpress v7.1 [37] was run on a computer with two 6-core processors (Intel Xeon X5680) and 192 GB of RAM.

V. CONCLUSIONS AND FURTHER WORK

This paper analyzed some key aspects of the transmission network investment problem that optimally balances preventive and corrective control within a probabilistic security model. This was then used as a benchmark to assess the performance characteristics of the conventional deterministic concept. We highlighted the inadequacies of the deterministic approach with respect to its inherent inability to optimize accurately the portfolio of pre-fault and post-fault actions since the impacts of corrective actions (in the form, for example, of SPS or demand side actions) and occurrence of "non-credible" events require explicit consideration of the likelihood of various outages. We concluded that deterministic approach drives less efficient and potentially more risky system operation that ultimately leads to inefficient network investment.

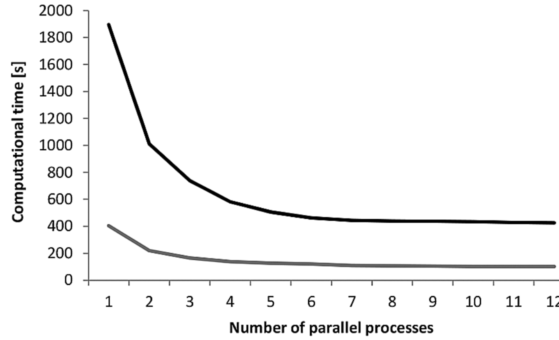

Fig. 5. $\mathrm{T}+\mathrm{O}+\mathrm{X}$ computation times when considering all operating states (upper line) and the umbrella states (lower line) according to the number of parallel processes run.

Within the developed Benders decomposition based investment model, we proposed a new algorithm that can efficiently identify relevant outages and filter out those that do not contribute to finding the optimum operating solution. We demonstrated that the optimum probabilistic solution is driven by a set of umbrella outages that is composed of a mix of events that include various types of N-k outages which change depending on the actual operating condition.

Presented model may be used to support the evolution to probabilistic approach to network operation and design to ensure that network investment and operational criteria do not impose unnecessary barriers to entry and do not prevent a timely connection of new generation and demand.

In order to facilitate increased penetration of corrective control, however, further research is needed, particularly to quantify the risk profile of the system with increased usage of information infrastructure (i.e., communication links, instrumentation and control center). As discussed in [38], potentially adverse impact of the increasing reliance on the information and communication infrastructure including the implication on the resilience of the power system, will need to be considered.

In this context, the probabilistic framework provides the basis for assessing the risks associated with information infrastructure and hence to determine whether the increased application of corrective control could displace investment in infrastructure reinforcement. Consequently, the model presented in this paper is being enhanced to deal with multiple operating states derived from an outage (and not only one like in this paper) due to the possibility of cascading outages and the presence of hidden failures, similarly to the model shown in [39], and to include the interdependency with the communication network like the model shown in [40].

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